Electronic Version
Stylesheet Version v1.1.1

Description

Hydraulic Optimization of Drilling Fluids in Borehole Drilling

Cross Reference to Related Applications

[0001] This application is a non-Provisional application of U.S. Provisional application serial number 60/319,481 filed on August 21, 2002, which is incorporated by reference herein in its entirety.

Background of Invention

[0002] 1. Field of the Invention.

[0003] This invention relates to the hydraulic optimization of the liquid drilling fluid (mud) used when drilling boreholes into the earth for extraction of minerals. In particular, the present inventions allows the pressure and flow rate of the mud to be set as desired at different locations in the drilling string to optimize the drilling operation.

[0004] 2. Description of the Related Art.

[0005] When drilling boreholes into the earth, a liquid drilling

fluid, now well known simply as "mud"or "drilling mud", is often used to flush the cuttings from the bottom of the well bore to the surface. Originally, the mud was used only for flushing out the cuttings. It was not long however, before the drilling industry realized that the drilling mud, often supplied at high pressures and high flow rates, could be used to power other devices in the drill string that support the drilling operation, including for telemetry pressure pulses, power, and for primary well control.

[0006] Today, it is now commonplace to have numerous tools in the drilling string which use the drilling mud to supply power for their operation. Such tools include drill bits, drilling motors, drilling turbines, rotary directional drilling devices, mud driven electric generators, hole opening devices, measuring while drilling tools, downhole communication devices, and many others. Although the drilling operation is enhanced by the use of these tools, it is well known that the hydraulics of the drilling fluid exiting the drill bit is one factor which most often determines drilling progresses and efficiency. The drill bit hydraulics determines how well the formation cuttings are cleaned from the drilling bit and transported to the surface.

[0007] A primary factor in the cost of drilling the borehole is the

drilling rate of penetration. Since this rate of penetration is profoundly affected by the drill bit hydraulics, it is very important to provide proper pressure and flow rate of the drilling fluid as it exits the drill bit through discharge orifices.

[0008] Drill bits typically have fixed size nozzles for discharge orifices, during a single run into the hole. Since one bit may be used in a wide range of applications, and may drill through differing lithologies, it is necessary to be able to change the hydraulic discharge characteristics through those nozzles. The need for multiple orifice sizes in drill bits is typically addressed by having interchangeable nozzles of different sizes for the bits, or orifice arrangements, such as shown in US Patent No. 6,277,316, that are adjustable. In either case, the orifice size is set at the surface and remains the same until the bit is once again returned to the surface.

[0009] Often, however, as drilling progresses the changes in the formations being drilled affect how well the formation cuttings are cleaned and transported. The nozzle size initially selected may no longer be the best for these changing formations. In order to compensate, the flow rate of the drilling fluid supplied to the bit if often changed at the

surface. Unfortunately, because optimizing the hydraulics of the drill bit involves both the area of the discharge orifice and the flow rate of the drilling fluid, true optimization seldom happens. Typically, to fully optimize the hydraulics, the drill bit would have to be returned to the surface and the nozzles replaced with ones with different orifice areas. This is a very expensive process; so true optimization rarely is achieved.

[0010] To complicate the issue, if there are other mud-powered devices in the drill string, their operation is affected by the flow rate change. Since each mud-powered device in the drill string "robs" a portion of the total hydraulic energy of the drilling fluid, any change in the flow rate may profoundly affect the performance of that device. As a consequence, there is often a juggling act in progress to supply the proper amount of flow to all the mud-powered devices in the drill string and also to the drill bit. Under these conditions, providing the optimum pressures and flows to each mud-powered device in the drill string is difficult at best. Oftentimes, one or more of the mud-powered devices are left to operate marginally.

[0011] In addition, because it may be difficult to determine how changing the pressure and flow rate of the drilling fluid

will affect these the mud-powered devices, many decisions on how to operate these devices adversely affect the overall drilling performance.

[0012] Many of the devices used downhole have valving and/or orifices that relieve the drilling fluid from within the drill string to the well bore, such as the relief valve described in US Patent No. 5,911,285. One type of device utilizing valving to various types of fixed orifices that can be switched on as the device is activated during drilling is an "on demand" hole opener. Still other devices provide fixed orifices, (or "chokes" as they are sometimes called) in the drill string to create a pressure drop along the drill string without venting to the borehole.

[0013] Although these devices are well known, it is not presently possible to adjust the flow rate and pressure drop through them.

[0014] It is therefore desirable to be able to adjustably select the pressure drop and/or flow rate across each mud-powered device in a drill string independently of each other. At the same time, it is also desirable to adjustably control the size of the fluid discharge orifices in drill bits.

SUMMARY OF INVENTION

[0015] The present invention is a method and apparatus to con-

trol the pressures and flows across fluid using devices used in drill strings for drilling boreholes. A method for optimizing drilling fluid hydraulics when drilling a well bore is disclosed. The drilling fluid is supplied by a surface pump through a drill string to a drill bit. The method has the step of adjusting the flow rate of the surface pump and a fluid pressure drop across the drill bit while drilling, such that the drilling fluid hydraulics are optimized for a given drilling condition.

[0016] Also disclosed is a drill bit with discharge orifices or nozzles which are adjustable such that the orifice size may be changed while drilling, without removing the drill string from the hole. There may be a plurality of nozzles on the face of the bit that may selectively turned on or off such the total flow rate and pressure drop through the bit is adjusted.

[0017] Also disclosed is a downhole motor with adjustable interference fit. The fit is adjustable by varying the flow rate and pressure drop across the motor while in operation. In addition, the pressures and temperatures of the drilling fluid above and below the motor may be monitored so that the interference may be optimally adjusted. Once the motor hydraulics are optimized, the flow then proceeds to

other devices, and finally to the drill bit.

[0018] In order for the flow through all the devices in the drill string to also be optimized, the flow through the motor (or other device) is adjusted in a manner selected from the group consisting of restricting the fluid flow, bypassing the fluid flow and relieving the fluid flow, thereby setting the pressure drop and the fluid flow rate through each device. As required for the overall system, the flow from the surface pump is increased or decreased as necessary.

BRIEF DESCRIPTION OF DRAWINGS

[0019] Figure 1 is a partial section view of a drill rig drilling a borehole into the earth.

[0020] Figure 2 is partial section of a side view of a fixed cutter drill bit.

[0021] Figure 3 is a perspective view of a rolling cutter drill bit.

[0022] Figure 4 is a section view of a fixed cutter drill bit fitted with a switchable flow selector valve.

[0023] Figure 5 is a section view of a drill bit fitted with controllable variable flow restriction devices.

[0024] Figure 6 is a schematic view of a fluid using device for downhole drilling operations of the present invention.

[0025] Figure 7A is an end section view of a Moineau type drilling

motor of the present invention.

[0026] Figure 7B is a side section view of a Moineau type drilling motor of the present invention.

DETAILED DESCRIPTION

[0027] Referring now to Figure 1, when drilling boreholes 10 into earthen formations 12, it is common practice to use a bottom hole assembly 14 as shown in Figure 1. The bottom hole assembly (BHA) 14 is typically connected to the end of the tubular drill string 16, which is typically rotatably driven by a drilling rig 18 from the surface. In addition to providing motive force for rotating the drill string 16, the drilling rig 18 also supplies a drilling fluid 20 under pressure and flow created by a surface mud pump 22, through the tubular drill string 16 to the bottom hole assembly 14. The drilling fluid 20 is typically laden with drilled abrasive formation material, as it returns to a mud tank 24 and is then repeatedly re-circulated through the borehole 10.

[0028] In the BHA 14, may be drilling fluid using devices 26 including a drill bit 28. These fluid using devices 26 may be one or more of drilling motors, drilling turbines, rotary directional drilling devices, mud driven electric generators, hole opening devices, measuring while drilling tools, and

downhole communication devices.

[0029] The present invention is drawn to a method and apparatus to control the pressures and flows across these fluid using devices 26 used in drill strings 16 for drilling boreholes 10 to optimize the drilling fluid hydraulics when drilling a well bore 10. The method has the step of adjusting the flow rate of the surface pump 22 and a fluid pressure drop across the drill 28 bit while drilling, such that the drilling fluid hydraulics are optimized for a given drilling condition.

[0030] To optimize the fluid hydraulics for a given drilling condition the flow through fluid using devices 26 is adjusted in a manner selected from the group consisting of restricting the fluid flow, bypassing the fluid flow and relieving the fluid flow, thereby setting the pressure drop and the fluid flow rate through each device. As required for the overall system, the flow from the surface pump 22 is increased or decreased accordingly, as necessary.

[0031] In one embodiment, the drill bit 28 may be a fixed cutter type drill bit 30 as shown in figure 2. The fixed cutter drill bit 30 has a longitudinal axis 32, a bit body 34 with a first end 36 which is adapted to be secured to the BHA 14. Typically, threads 38 are used for the attachment, but

other forms of attachment may also be utilized. At the second, opposite end 40 of the bit body 34 is the cutting face 42 of the fixed cutter drill bit 30.

[0032] During operation, the bit body 34 is rotated by an external means while the cutting face 42 of the fixed cutter drill bit 30 is forced into the formation 12 being drilled. The rotation under load causes cutting elements 44 to penetrate into the formation 12 and remove it in a scraping and/or gouging action.

[0033] The bit body 34 has internal passaging 36 with allows the pressurized drilling fluid 20 supplied from the surface pump 22 to flow through a plurality of nozzle orifices 46. These nozzle orifices 46 discharge the drilling fluid 20 to clean and cool the cutting elements 44 as they engage the material 12 being drilled. The drilling fluid 20 also transports the drilled material to the surface for disposal.

[0034] In another embodiment the drill bit 28 may be a rolling cutter type drill bit 50 as shown in Figure 3. A rolling cutter drill bit 50 is also commonly called a rock bit, a rolling cutter rock drill bit or an oilfield drill bit. Similar to the fixed cutter drill bit 30 already described, the rolling cutter drill bit 50 has a longitudinal axis 52, a bit body 54 with a first end 56 which is adapted to be secured to the

BHA 14. Typically, threads 58 are used the attachment, but other forms of attachment may also be utilized. Typically, the body of the rolling cutter drill bit 50 has three legs 60. Attached to each leg 60 is a rotatably mounted rolling cutter 62. Attached to each rolling cutter 62 are hard, wear resistant cutting inserts 64, which are capable of engaging the earth formation 12 to effect a drilling action and cause rotation of the rolling cutter 62.

[0035] The bit body 54 has internal passaging (not shown) with allows the pressurized drilling fluid 20 supplied from the surface to flow through a plurality of nozzle orifices 66. These nozzle orifices 66 discharge the drilling fluid 20 generally toward the rolling cutters 62 and the material 12 being drilled, in a manner similar to that of the fixed cutter drill bit 30 just described.

[0036] In practicing one embodiment of the present invention, it is desirable to adjust the hydraulic flow through the nozzle orifices of the drill bit 28, 30, 50 as the optimum hydraulic horsepower of the drilling fluid flowing through these orifices often changes during drilling.

[0037] As shown in Figure 4, one way to adjust the hydraulic flow through the nozzle orifices in a drill bit 30 is to fit a selector valve 70 into a bit body 34. As drilling progresses,

the selector valve 70 may be operated to switch the flow from one set of nozzle orifices 72 to one or more alternate nozzle orifices 74. The selector valve 70 may have several operating positions such that numerous configurations are possible. The configuration chosen would be the one best suited for the present drilling condition. Once the selector valve 70 has been set in a particular configuration, the flow rate of the surface mud pump 22 is adjusted to the proper value for that configuration. In this manner, the optimal pressure and flow rate for the drill bit under a given set of drilling conditions may be adjusted. If there are other fluid using devices 26 in the drill string 16, each of these may also be adjusted for optimal operation as well, as will be described.

[0038] As shown in Figure 5, an alternate way to adjust the hydraulic flow through the nozzle orifices in a drill bit 50 is to fit variable restrictions 80, 82 into the nozzle orifices 84, 86 in a bit body 54. These variable restrictions 80, 82 are operated by servo type motor devices 88, 90, (or other suitable devices) which are controlled from a suitable MWD tool electronics device through short hop communications, or other known systems suitable for this type of control. As indicated by numeral 92 in Figure 2 the servo-

motor and the restriction may be combined into a single package which is inserted into an existing flow passage 36 in a drill bit. Again, once the nozzle orifices are adjusted to the optimum value, the flow rate of the surface mud pump 22 is adjusted to the proper value for that configuration. In this manner, the optimal pressure and flow rate for the drill bit under a given set of drilling conditions may be adjusted.

[0039] However, once the drill bit pressure and flow is adjusted, any other fluid using devices 26 in the drill string 16 may also need to be adjusted for optimal operation as well. This is done in reference to Figure 6.

[0040] Figure 6 is a schematic diagram of flow arrangements possible in other fluid using devices 26. The device itself is indicated by numeral 100 as a variable flow restrictor. In use, it is desirable to adjust the pressure drop and the flow rate through the device itself 100. Since it is also necessary to set the flow rate at the exit 102 of the fluid using device 26, it may be necessary to either divert flow around the device itself 100 with a variable flow restrictor 104, restrict the flow into the device itself 100 with a variable flow restrictor 106, or restrict the flow out of the device itself 100 with a variable flow restrictor 108, or to di-

vert flow into the borehole above the device itself 100 with a variable flow restrictors 110 and 112.

[0041] In practice only one or two of these variable flow restrictors 104, 106, 108, 110 and 112 would generally be used, depending upon the type of device and the desirable accuracy level.

[0042] In any case, in order to properly set the variable flow restrictors 104, 106, 108, 110 it is necessary to know one or more of the temperature, flow rate and pressure through the fluid using device 26. In order to make these readings, one or more sensors 114, 116, 118, 120 are used to provide the required temperatures, flow rates and/or pressures in the flow passages 101 of the device required to optimize the tool. Once the optimum pressure drop and flow rate is calculated, and knowing the flow rate which must be maintained by the fluid exiting the fluid using device 26, the variable flow restrictors 104, 106, 108, 110 and 112 and if necessary the flow rate of the surface pump 22 - are then set as required to produce these values.

[0043] Each fluid using device 26 may thus be adjusted to optimum hydraulic operating values and still permit the drill bit 28 to be operated at its optimum hydraulic setting.

[0044] On such fluid using device 26 is a positive displacement downhole motor 200. Positive displacement motors 200, as shown in cross section views in Figures 7A and 7B dominate oilfield operations and offer distinct operational and economic advantages over conventional rotary drilling in many conditions. Downhole motors 200 offer the option of drilling in either a traditional rotary mode or a sliding mode in which the hole follows the direction of the bent housing on the motor 200. In directional drilling applications, downhole motors 200 permit control of the wellbore direction and thus, more effective deviation control than conventional rotary methods.

[0045] Moineau type positive displacement motors 202 consist of three major sub-assemblies, a power section, comprising a rotor 204 and a stator 206, which converts hydraulic energy into mechanical rotary power, a transmission section (not shown), which transmits rotary drive from the power section to the bearing section and also incorporates the adjustable bent housing and a bearing section (not shown), which supports axial and radial loads during drilling and transmits the rotary drive to the bit through a drive shaft.

[0046] The power section within the motor 202 converts hy-

draulic power from the drilling fluid into mechanical power to turn the bit. This is accomplished by reverse application of the Moineau pump principle. Drilling fluid is pumped into the motor"s 202 power section at a pressure that causes the rotor 204 to rotate within the stator 206. This rotational force is then transmitted through a transmission shaft and drive shaft to the bit.

[0047] Typically, the rotor 204 is manufactured of corrosion-resistant stainless steel. It usually has a chrome plating applied to reduce friction and abrasion. Tungsten-carbide coated rotors 204 are also available for reduced abrasion wear and corrosion damage. The stator 206 consists of a steel tube with an elastomer lining molded into the bore. The elastomer in the lining is formulated specifically to resist abrasion and hydrocarbon-induced deterioration.

[0048] The rotor 204 and stator 206 have similar helical profiles, but the rotor 204 has one less spiral, or lobe 208, than the stator 206. In an assembled power section, the rotor 204 and the stator 206 form a continuous seal at their contact points along a straight line, which produces a number of independent cavities. As fluid (air, mud or water) is forced through these progressive cavities, it causes the rotor 204 to ratchet around inside the stator 206. This

movement of the rotor 204 inside the stator 206 is called nutation. For each nutation cycle, the rotor 204 turns the distance of one stator lobe 210 width. The rotor 204 must nutate for each lobe 210 in the stator 206 to complete one revolution of the bit box. A motor 202 with a 7:8 rotor/stator lobe configuration and a speed of 100 rpm at the bit box will have a nutation speed of 700 cycles per minute.

[0049] The lobes 208, 210 on the rotor 204 and stator 206 act like a gear bob. As their numbers increase for a given motor 202 size, the motor"s torque output generally increases and its output shaft speed generally decreases. Because power is defined as speed multiplied by the torque, a greater number of lobes 208, 201 in a motor 202 does not necessarily produce more horsepower. Motors 202 with more lobes 208, 210 are actually less efficient because the seal area between the rotor 204 and stator 206 increases with the number of lobes.

[0050] Motors 202 are usually assembled with the rotor 204 sized larger than the stator 206. This produces a strong positive interference seal, causing a positive fit. Motors 202 run with a rotor 204 mean diameter more than 0.02 in greater than the stator 206 minor diameter at downhole

conditions are very strong (capable of producing large pressure drops), but they usually have a reduced life because premature chunking of the rubber portion of the stator 206 occurs.

[0051] If increased downhole temperatures are anticipated, the amount of positive fit is reduced during motor 202 assembly to allow for the swelling of the elastomer lining in the stator 206. An oversize stator 206 is usually required to obtain the correct amount of interference between the rotor 204 and the stator 206 for temperatures above 200 degF. If the anticipated circulating temperature of a well is above approximately 225 degF, the interference fit must be a flush or negative fit, in which the rotor 204 mean diameter is the same size as, or smaller than the stator 206 minor diameter when the motor 202 is assembled in the shop.

[0052] Chunking describes a stator 206 in which the rubber across the top of the lobes 210 has apparently ripped away. Chunking occurs when the strength of the friction force between the rotor 204 lobe 208 and the stator 206 lobe 210 exceeds the strength of the rubber in the stator 206. The magnitude of the friction force between the rotor 204 and the stator 206 is affected by the lubricity of

the mud, interference fit between the rotor 204 and the stator 206, nutation speed and pressure drop.

[0053] Chunking prevention is a combination of techniques involving rotor/stator fit, bottomhole temperature, drilling mud selection, proper operation, lost circulation material, nozzled rotors 204, dogleg severity and stator 206 age tracking.

[0054] The interference fit of the rotor 204 and stator 206 is critical to the performance and overall life of the elastomer in the stator 206 tube. A motor 202 with too much interference (the rotor 204 bigger than the stator 206) runs with a high differential pressure, but will generate chunking after only a few circulating hours (i.e., 6-8 hrs). The chunking may be uniform, or follow a spiral pattern through the motor 202.

[0055] A rotor/stator interference fit that is too loose produces a weak motor 202 that stalls at low differential pressure. Motor 202 stalling is the condition in which the torque required to turn the bit is greater than the motor 202 is capable of producing.

[0056] When a motor 202 stalls, the rotor 204 is pushed to one side of the stator 206 and mud is pumped across the seal face on the opposite side of the rotor 204. The lobe 210

profile of the stator 206 must deform for the fluid to pass across the seal face. This causes very high fluid velocity across the deformed top of the stator 206 lobes 210 and leads to chunking.

[0057] The circulating temperature dictates the amount of interference in assembling the rotor 204 and the stator 206. The higher the anticipated downhole temperature, the less compression required between the rotor 204 and stator 206. The reduction in interference during motor 202 assembly compensates for the swell downhole of the elastomer because of temperature and mud properties. If there is too much interference between the rotor 204 and the stator 206 at operating conditions, then the stator 206 will experience high shearing stresses, resulting in fatigue damage. This fatigue leads to premature chunking failure. Failure to compensate for stator 206 swelling resulting from the anticipated downhole temperature is a leading cause of motor 202 failures.

[0058] It is therefore desirable to adjust the interference fit of the rotor 204 and stator 206 during drilling to optimum values to accommodate changes in drilling conditions.

[0059] The proper interference fit of the motor 202 may be calculated using information from pressure sensors and

temperature sensors 114, 116, 118, 120 as described previously, and then the interference may be set by controlling the pressure drop across the motor 202 by adjusting one or more of variable flow restrictors 104, 106, 108, 110, as previously described.

[0060] Whereas the present invention has been described in particular relation to the drawings attached hereto, it should be understood that other and further modifications apart from those shown or suggested herein, may be made within the scope and spirit of the present invention.